ACCESSION #: 9103210199

LICENSEE EVENT REPORT (LER)

FACILITY NAME: McGuire Nuclear Station, Unit 1 PAGE: 1 OF 18

DOCKET NUMBER: 05000369

TITLE: A Unit 1 Reactor Trip Occurred Due to A Loss Of Offsite Power Caused By An Inappropriate Action, A Management Deficiency, and An Equipment Failure

EVENT DATE: 02/11/91 LER #: 91-001-00 REPORT DATE: 03/13/91

OTHER FACILITIES INVOLVED: DOCKET NO: 05000

OPERATING MODE: 1 POWER LEVEL: 100

THIS REPORT IS SUBMITTED PURSUANT TO THE REQUIREMENTS OF 10 CFR SECTION:
OTHER: Special Report

LICENSEE CONTACT FOR THIS LER:
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COMPONENT FAILURE DESCRIPTION:
CAUSE: SYSTEM: COMPONENT: MANUFACTURER:
REPORTABLE NPRDS:

SUPPLEMENTAL REPORT EXPECTED: No

ABSTRACT:

On February 11, 1991, A Unit 1 Reactor Trip occurred at 1355:13. Prior to the event, Unit 1 was operating in Mode 1 (Power Operation) at 100% power. The Reactor was tripped by a Nuclear Instrumentation (NI) Power Range Hi Flux Rate signal. The trip signal was initiated when offsite power to the unit was lost because a blackout occurred in the 230KV switchyard. The blackout as a result of a failed relay in conjunction with a post modification test being performed on a newly added relay circuit in the switchyard. Subsequent depressurization of the Main Steam (SM) system resulted in a Safety Injection (SI). An Unusual Event was declared at 1420 due to Loss of Power and SI. The Technical Support Center (TSC) was activated as a conservative measure and TSC personnel made the required notification to the NRC. A thorough technical review was performed on the event and, consequently, a decision was made by Station Management (with concurrence of the NRC) to restart the Reactor. Unit 1 was returned to Mode 2 (Startup) operation on February 13, 1991, at approximately 0345. This event is assigned causes of Inappropriate Action, Management Deficiency, and an Equipment Failure.

END OF ABSTRACT

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EVALUATION:

Background

McGuire Nuclear Station consists of two generating units and the auxiliary equipment for the two units. It functions in association with the McGuire 230 KV and 525 KV Switchyards [EIIS:FK].

Each unit generates power at a voltage of 24 Kilovolts (KV) that is delivered through two half-size step-up transformers [EIIS:XFMR] to the McGuire Switchyard by overhead transmission lines. Unit 1 is connected to the 230 KV switchyard, while Unit 2 is connected to the 525 KV switchyard. The output of each unit is then delivered into Duke's transmission system through switchyard power circuit breakers [EIIS:52] (PCB) in a breaker and a half configuration and transmission lines. (See page 18 of 18.)

Normal auxiliary power on each unit is supplied by two auxiliary power transformers (24 KV/6.9 KV) each rated at 100 kilovolt amperes (KVA). Each auxiliary transformer has two secondary output windings, supplying normal power to two sections of 6.9 KV switchgear [EIIS:SWGR] and standby power to two other sections.

The 230 KV and 525 KV switchyards have two electrical buses [EIIS:BU] and a number of circuit breakers that connect the generators [EIIS:GEN] with the transmission system. The buses provide junction points for the power exchange between generators and the system. PCBs interrupt flow of power and isolate any section that may be faulted. To distinguish between the two buses in each switchyard, they are designated as the red bus and the yellow bus. In addition to naming the buses, each power circuit breaker is assigned a number, which aids in identifying the individual breakers. Both, switchyards are used to connect two circuits between the red and yellow buses.

The 525 KV and 230 KV switchyards are connected through an autotransformer which permits power distribution between the two voltage levels.

Seven pairs of transmission lines connect the 230 KV switchyard at McGuire with the rest of the Duke system. The Craighead Lines and the Mecklenburg Lines connect with Harrisburg Tie Substation near Charlotte, N.C. The Norman lines and the Schoonover lines tie with Riverbend Steam Stations switchyard. The Blackburn lines feed the Longview Tie Station near Hickory, NC. The Westport Lines tie with Marshall Steam Stations switchyard and the Cowans Ford Lines connect with Cowans Ford Hydro Plant.

Fault Pressure Relaying [EIIS:RLY] is used on the switchyard autotransformer as a supplement to the primary protective relaying. When internal transformer winding faults become severe, they produce large amounts of gases from the breakdown of the insulation [EIIS:ISL] materials. The expanding gases cause a rapid rise in the pressure on the insulating oil. Fault

pressure relays can sometimes detect these faults before the primary protective relays can.

Fault pressure relays are mounted on the outside of a transformer casing and use a bellows [EIIS:BE] mechanism to detect sudden changes in the transformer oil pressure.

If the fault, pressure relay(s) on the transformer detects a high rate of pressure rise on the insulating oil, indicating an internal winding fault, it will operate, through tripping logic, to initiate Lockout Relays [EIIS:86]. These lockouts will clear the faulted transformer by totally clearing and de-energizing the feeder breakers.

A breaker failure relaying scheme is provided for backup autotransformer fault protection. It ensures isolation of the autotransformer if the feeder breakers fail to trip when initiated for a fault condition. This is accomplished by opening all red and yellow bus PCBs in the 525 KV and 230 KV switchyards.

The directional distance phase relay [EIIS:21] 21LC is the primary fault protection of a transmission line. It protects all three phases of a transmission line for phase-to-phase, three-phase, and two-phase-to-ground faults. This relay is directional in that it will respond to fault current flow in one direction only. This direction is determined by comparing the line current flow with the bus voltage. The bus voltage is the non-changing quantity, or reference voltage. The directional distance relay detects faults within a certain distance of a lines local terminal by measuring the line impedance.

When directional distance relays are deprived of their operating voltage, it is possible that these relays will pick up from load current only. The loss of operating voltage is usually due to the malfunction of the voltage device or its associated circuits supplying this voltage. To prevent an undesirable trip from this occurrence, an instantaneous overcurrent phase relay [EIIS:67] 50P is installed to supervise each directional distance relay.

The directional distance phase relays (21LC), its associated overcurrent (50P) relay and its associated carrier (85) [EIIS:85] relay must be picked up to initiate tripping. No tripping will take place if the 21LC relay picks up, but the 85 relay and the 50P relay does not pick up.

The purpose of the Excore Instrumentation System (ENB) [EIIS:IG] is to monitor Reactor [EIIS:RCT] core leakage neutron flux and generate appropriate trips and alarms [EIIS:ALM] for various phases of Reactor Operation. The outputs of the source, intermediate, and power range detectors [EIIS:DET] are used to limit the maximum power output of the Reactor within their respective ranges and are used as inputs to monitor neutron flux from a completed shutdown condition up to 120 percent of full power. The power range detector provides power level indication and trip signals for Reactor protection,

alarms to warn of abnormal conditions, and signals for remote recording, indicating, and computing [EIIS:CPU] equipment.

Description of Event

On February 11, 1991, at approximately 1030, while Units 1 and 2 were operating at 100% power Transmission Department personnel began conducting a test of a modification which installed a new relay circuit. The relay circuit is a fault pressure relay switch 63FPX on the autotransformer which ties the 230KV switchyard to the 525KV switchyard. The scope of the testing involved simulating a fault pressure relay trip of the switchyard autotransformer bank. Since the system dispatcher would not allow the autotransformer to be deenergized because of system load, the test was conducted with the feeder breakers to the transformer closed. The trip coil [EIIS:CL] circuitry was blocked on the feeder breakers to prevent their tripping as a result of the test. Transmission personnel failed to open all affected downstream relay contacts which would have completely blocked the actuation of the autotransformer breaker failure relay scheme. This scheme is redundant to the primary lockout scheme (which was blocked) and is designed to clear a zone around a fault even if the PCBs fail to open. The next zone of protection in this case is to open all PCBs tied to the red and yellow bus. What follows is the sequence of events that occurred after the planning and implementation of the relay scheme blocking:

1) At approximately 1350, Transmission personnel initiated a simulated fault pressure relay operation by placing a jumper across appropriate terminals located in the autotransformer control panel.

2) The associated lockout relays (86AT and 86ATS) actuated as expected and did not open the autotransformer feeder breakers (as expected because they were blocked).

3) The breaker failure scheme recognized the fact that the autotransformer feeder breakers remained closed and assumed that a fault was still present that had not been cleared and opened the autotransformer feeder breakers.

4) The breaker failure scheme operated as designed and opened 28 PCBs clearing both red and yellow buses in the 525KV and 230KV switchyards.

5) At this point, Units 1 and 2 remained connected to the grid through their associated "half" breakers which connect the unit bus lines directly to outgoing transmission tie lines. (Craighead White and Mecklenburg Black, for Unit 1). (See page 18 of 18.) Each outgoing line is sized to handle approximately one half of full unit output.

6) At an unknown time before/during the event, distance relay 21LC failed closed. This is a distance relay which monitors the

Craighead White transmission line. This defective relay satisfied the logic required to trip PCB8 when the red and yellow bus cleared. This provided abnormally high current through the line and completed the permissive to trip PCB8. Thus, the PCB tripped clearing the Craighead line and eliminated 1 of the 2 remaining Unit 1 ties to the grid. (See page 18 of 18.)

7) The loss of the Craighead White transmission line caused full load current to be diverted through PCB11 to the Mecklenburg Black line. This caused an overload condition on PCB11.

8) PCB11 tripped 0.2 seconds later at 1355:04, on overcurrent which cleared the Mecklenburg Black line. This was the only remaining connection of Unit 1 to the grid resulting in a loss of all off site power to Unit 1.

9) The unit had not received a runback signal at this point and full load current from Unit 1 was subsequently redistributed to unit auxiliaries. This induced a voltage transient in the station electrical distribution system.

10) Since the generator was now producing more electricity than required by station loads, frequency began to rise. This increased Reactor Coolant (NC) [EIIS:AB] pump speed.

11) The Nuclear Excore Instrument System (NI) recognized a change in Reactor power from 100 percent to 104 percent power in approximately 1 second and initiated a high flux rate Reactor Trip signal. The Reactor tripped at 1355:13, followed by a Turbine [EIIS:TRB] trip at 1355:14.

Following the Reactor and Turbine Trips, Diesel Generators (D/G) [EIIS:DG] 1A and 1B started and began sequencing on blackout load groups.

Seconds later, the Control Room [EIIS:NA] Senior Reactor Operator (SRO) initiated emergency procedure EP/1/A/5000/01, Safety Injection or Reactor Trip, which requires manually exercising the Reactor Trip switches and performing other actions to stabilize the unit. He also verified that a Safety Injection (SI) [EIIS:BG] had not occurred.

NC system temperature and Main Steam (SM) system [EIIS:SB] pressure started decreasing. NC system temperature was trending toward 557 degrees Fahrenheit as expected. The NC system was now being cooled by natural circulation.

Operations (OPS) personnel realized that SM system pressure was decreasing below no load value. They attempted to reset the Moisture Separator Reheaters (MSRs) [EIIS:MSR] and remotely close valve 1SM-15, SM to Second Stage Reheaters. They were unsuccessful in this attempt because was no power available. Also, steam line drain valves were open and could not be remotely closed. This contributed to high SM system cooldown rate.

OPS personnel throttled the Auxiliary Feedwater Control valves [EIIS:BA] to the full closed position to limit cooldown. Also, they were in the process of manually closing valves 1SM-15 and 1SP1, SM to Feedwater Pump Turbine 1A, and 1SP2, SM to Feedwater Pump Turbine 1B, when, at 1412, approximately 17 minutes after the Reactor Trip, the low steam line pressure SI setpoint was reached.

After the SI, a SM Isolation signal automatically initiated which caused the Main Steam Isolation Valves (MSIV) to close. This stopped heat removal from the NC system and caused pressure and temperature to increase, and NC system Power Operated Relief Valves (PORV) 1NC-32 and 1NC-36 opened. PORV 1NC-34 did not lift due to being jumpered closed per work request 142869. No Pressurizer [EIIS:PZR] code safety valves lifted.

Lower-Containment [EIIS:NH] temperature and pressure started increasing due to loss of containment ventilation. This caused the lower ice condenser [EIIS:BC] doors to briefly open. OPS personnel then exited procedure EP/1/A/5000/01 and entered procedure EP/1/A/5000/02, High Energy Line Break Inside Containment. Containment pressure eventually peaked at 0.76 psig.

An Unusual Event was declared at 1420. Concurrently, OPS personnel verified that all SI termination criteria as described in procedure EP/0/A/5000/02 were met. The SI signal was reset at 1422.

By 1435, power was fully restored to the switchyard and was available to the 6.9 KV buses in the plant. Shortly afterwards, OPS personnel began transferring loads from the D/G supply to the normal 4160 volt supply bus.

The Technical Support Center (TSC) and Operations Support Center (OSC) were activated as a conservative measure and subsequently fully activated at 1503 with the Station Manager as Emergency Coordinator.

TSC personnel determined that there was no radiological concern and decided to enhance unit cooling by venting steam through the SM system atmospheric PORVs. The Main Condenser had been made unavailable as a result of the unit blackout.

By 1630, the unit was stabilized to a point that allowed the unit to be shutdown in a routine manner. Subsequently, TSC personnel directed OPS personnel to commence procedure OP/1/A/6100/02, Controlling Procedure for Unit Shutdown.

The OSC and TSC were deactivated at 1735.

The Station Manager called for an independent review to evaluate the event prior to restarting the unit. Many station groups, Design Engineering, and Transmission Department personnel participated in this technical review. This technical review encompassed the following items:

- NC system radiochemistry samples were taken and found to be within normal parameters. This indicated Reactor Core integrity was maintained.

- A visual survey of Unit 1 Containment was performed by OPS personnel and no problems were found.

- Design Engineering Department and Maintenance Engineering Services (MES) personnel walked down the PZR PORV discharge pipe and no problems were found.

- The ice condenser, ice bed, and doors were surveyed by MES personnel and were determined to be undamaged.

- Design Engineering Department personnel evaluated the temperature spike in containment and determined there was no immediate equipment/structural damage.

- OPS personnel cycled the PZR PORV a number of times and there was no evidence of high discharge pipe temperature which would have indicated NC system leakage through the valve seat.

- One malfunctioning lower Containment Ventilation (VL) power supply was repaired as directed by Work Request 144402.

- MES and Performance (PERF) personnel began performing an evaluation of the high flux rate trip signal.

- Steam Generator blowdown valve 1BB-8 did not operate properly. This was repaired and functionally verified as directed by Work Request 144386.

- The Operator Aid Computer (OAC) was down intermittently during the event. Instrument and Electrical (IAE) personnel repaired and returned the OAC to service.

- OPS personnel reviewed Emergency Operating Procedures on closure of MSIVs to evaluate the need for adding steps to manually shutoff steam line drains.

- Relay 21LC in the switchyard was repaired by Transmission Department personnel.

- No other electrical problems were found.

- The Chemical and Volume Control (NV) system was surveyed and all was determined to be normal.

After evaluating the facts associated with the event and correcting all equipment problems identified, it Was determined that it was safe and prudent

to restart the Reactor. Startup activities continued on a continuous basis and Unit 1 was returned to Operation on February 13, at 0345.

Conclusion

A cause of Misunderstood Verbal Instructions and Lack of Attention to Detail is assigned. Just prior to start of the modification, Charlotte Area Operating Center (AOC) and Transmission personnel anticipated that the autotransformer could be de-energized long enough to perform a post modification test within a short time of completing the job. It is Transmission Department policy to test new devices on operating equipment as soon as possible after they are installed to provide maximum assurance that the equipment is safe. The Relay crew performing the test was aware of this policy and was anxious to complete the checkout. The Relay Supervisor contacted the AOC several times that day and asked him to clear the autotransformer and grant permission to proceed with the test. At 1200, the Relay Supervisor contacted the AOC for permission to remove the autotransformer from service. The AOC in consultation with the System Operating Center (SOC) determined that the autotransformer should not be taken out of service at that time due to system load conditions. A discussion between the AOC and Relay Supervisor followed. They discussed performing the test with the autotransformer energized. The AOC was confident that the Relay crew personnel had the knowledge and expertise to perform the test with the autotransformer energized. They were faced with an unusual testing situation that they had not previously planned for and were reluctant to proceed. They had hoped that the autotransformer could be cleared before the end of the day.

The Relay Supervisor was mindful that (since the autotransformer was still energized) the downstream relay logic must be blocked to prevent the autotransformer from detecting a fault and tripping the feeder breakers during the test. He directed the Relay crew personnel to develop a plan to open the relay contacts so that simulating a transformer fault pressure signal would actuate the relay logic but would not open PCBs 1, 3, 52, 53 to lockout the autotransformer. The Relay crew personnel then held a brainstorming session on how to perform the test with the autotransformer energized. The Relay crew technicians researched the drawings and reviewed their plan with the Relay Supervisor. The relay drawings were complicated, confusing, and hard to read. There were two separate downstream relay contacts that should have been opened to block PCBs, 1, 3, 52, 53 opening. However, the field crew failed to find one of these logic protection paths in their search of the drawings. The Relay Supervisor did not identify this during his review. Therefore, only one of these paths was identified and only one of the contacts was opened. Both contacts should have been opened to block the trip.

A mitigating factor is that at 1300, the Relay Supervisor noticed that another Transmission Department crew had arrived and was working in the near vicinity of the autotransformer. He knew the autotransformer fault protection was questionable since the circuit had not been tested yet. He

also was aware that the autotransformer was in a loaded condition and if the circuit did not work properly under fault conditions, that the autotransformer could fail catastrophically, endangering the second Transmission Department crew. He also realized that the end of the work day was approaching and he did not want to leave the autotransformer protective relaying in a degraded state overnight. At 1339, he asked the onsite Operations Department Service Representative to call the AOC and grant permission to proceed with the test.

A three party conversation followed with instructions being relayed between the Operations Department Service Representative and the Relaying Supervisor. The AOC believed that the Relay Supervisor was to make a decision regarding the test and call him back before proceeding. The Relay Supervisor believed that he had been given permission to proceed with the test.

A cause of Management Deficiency is assigned due to a Lack of Policy and Inadequate Groups Interface. The majority of the McGuire switchyard was controlled by Transmission Department Operating Division and System Operating Center Department personnel. Only the four PCBs (PCB8, 9, 11, 12 for Unit 1 and PCB58, 59, 61, 62 for Unit 2) that directly connect the Units to the grid were controlled by McGuire OPS Control Room personnel. Traditionally, only work on the four Unit related PCBs had required concurrence from System or Area Operations personnel plus the additional concurrence by McGuire OPS Control Room personnel. Since this modification was outside the traditional boundary of plant owned equipment, it was considered exempt from the Nuclear Station Modification program and the station work control process. Transmission Department and AOC personnel did not consider it appropriate to notify McGuire OPS Control Room personnel that work was in progress in the switchyard since it was out of their field of expertise. Consequently, this activity was in progress without any knowledge by McGuire OPS Control Room personnel. However, switchyard activities outside this boundary can and do impact the station. Also, had the plant electrical system been in a degraded state (i.e., 1 D/G out of service), the Duke System load dispatchers would not have been aware of this. Prior to this event, due to the existing division of equipment ownership, there was no agreement between Station Operations, Transmission Department, AOC and SOC of how activities in the switchyard outside plant owned equipment boundaries should be handled.

Transmission Department personnel have historically avoided errors in the switchyard through a variety of informal means such as training on switchyard equipment and controls, verification of wiring by an independent worker, strict communication discipline including repeatback for breaker alignment orders, and coordination through experienced dispatchers. Verbatim procedure compliance has normally not been required, and complete procedures with specific testing guidance have not usually been available. The technician crews are expected to utilize their extensive collective experience and training to determine the best methods for installing modifications and performing tests.

This event is also assigned a cause of Equipment Failure because the switchyard blackout and subsequent Unit trip would not have occurred if protective relay 21LC had not failed. During normal system conditions, the 85 relay is closed and the 21LC relay trip contact is held open by voltage present in the relay. This open contact verifies there is not a fault present on the transmission line. However, after the event, the 21LC relay contact was found stuck closed. This closed contact provided a trip path through the 85 relay and the 50P overcurrent relay an the Craighead White transmission line. One half of Unit 1 current (1500 Amps) flowing through the transmission line exceeded the overcurrent trip setpoint (1200 Amps) of the 50P relay. This combination of factors satisfied the logic which indicated that a fault was being fed on the Craighead White transmission line and PCB8 opened to clear the indicated fault. The switchyard was designed to handle a single failure which included a lockout of the main buses; however, the addition of, a latent relay failure exceeded the capability of the switchyard design to maintain power.

Transmission Department personnel attempted to determine why relay 21LC was stuck closed. System operating data indicated that there had not been any faults on the transmission line (since the relay preventative maintenance) which would have caused the contact to pick up. The status indicator on the relay did not show a trip coil activation. The relay was disassembled and inspected by knowledgeable Transmission Relaying and Metering Department personnel. They could find no magnetic, mechanical, or electrical abnormality that attributed to the contacts closing and remaining stuck closed. However, they suspected the cause to be a deposit of organics onto the contacts due to either outgassing caused by heat from internal electrical components or improper lubrication. This investigation is ongoing and the 21LC relay may be sent to a relaying manufacturer for further analysis of the defective components.

PERF personnel theorized that the high flux rate trip signal was initiated because the NI system recognized a change in Reactor power due to the thermalization process in the NC system. MES personnel theorized that the high flux rate trip signal was initiated due to the voltage transient in the station electrical distribution system. Neither of those theories have been proven and the investigation of same is ongoing.

OPS personnel responded to the transient in a timely manner. With the exception of relay 21LC, all equipment and systems operated within specifications as expected during this Reactor Trip. The TSC and OSC activation went very well. Concurrence to restart the unit was received by the NRC based on evidence that:

1. The plant equipment operated properly,

2. Plant OPS personnel responded correctly using appropriate procedures, and

3. A careful approach to restart was demonstrated by doing a comprehensive inspection of the plant and any needed corrective actions were taken.

The boron injection safety nozzle usage factor for this event was 0.017. The cumulative nozzle usage factor for all Unit 1 safety injection events to date is 0.102 with 7 significant safety injection events. The total allowable nozzle usage factor is 1.0 with NRC notification required at 0.70.

A review of the Operating Experience Program (OEP) data base for the previous 24 months prior to this event revealed no events involving a Reactor Trip in which the cause was an Inappropriate Action, A Management Deficiency, or an Equipment Failure where Transmission Department personnel were performing switchyard modification work. However, two previous events were documented in Problem Investigation Report (PIR) 2-M89-0233 and 2-M89-0209 involving the Transmission department where written communication was inadequate. Therefore, this problem is considered recurring.

This event is not Nuclear Plant Reliability Data system reportable.

There were no personnel injuries, radiation exposures, or uncontrolled releases of radioactive material as a result of this event.

CORRECTIVE ACTIONS:

Immediate:

1) OPS personnel implemented emergency shutdown and accident mitigation procedures EP/1/A/5000/01, Safety Injection or Reactor Trip, and EP/1/A/5000/02, High Energy Line Break Inside Containment.

2) The OSC and TSC were activated.

3) Offsite power was restored to the unit within 40 minutes (essential bus).

Subsequent:

1) An independent technical review of plant equipment was performed. This review revealed that the plant equipment operated properly and there was no major damage to it.

2) An interim switchyard work control policy to increase the offsite power system reliability was implemented. This policy requires the AOC Dispatcher to notify McGuire Control Room personnel of any activities in the switchyard that could affect the station. Also, when the station enters a degraded electrical system configuration, the McGuire Control Room SRO will notify the AOC Dispatcher. This will heighten the awareness of all work groups of increased station vulnerability during the degraded condition.

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3) Chemistry samples of the NC system were taken and found to be within normal parameters. This indicated that the Reactor Core was not damaged.

4) A survey of Unit 1 Containment was performed and no problems were found.

5) The ice condenser ice bed, and doors were surveyed and no problems were found.

6) Design Engineering Department personnel evaluated the temperature spike in containment and determined that there was no immediate equipment or structural damage.

7) Design Engineering Department and MES personnel surveyed the PZR PORV and discharge pipe and determined that there was no leakage through the valve seat.

8) Relay 21LC was repaired by Transmission department personnel.

9) The unit secondary side was surveyed and no problems were found.

10) Signs were placed on the switchyard gate which state: ATTENTION all circuits ia this switchyard can affect McGuire plant operation. Notify AOC at 382-0383/0384 prior to beginning any work in the switchyard.

11) Transmission Department personnel suspended all non-emergency work in the switchyard until a complete policy controlling switchyard activities is formulated.

12) Transmission Management personnel reviewed this event with appropriate personnel.

Planned:

1) MES, IAE, and PERF personnel will continue the evaluation of the cause for the NI high flux rate trip.

2) A multidepartmental task force has been set up to review administrative control of switchyard activities and develop a policy for control of the same.

3) Transmission Department personnel will complete the post modification test on the 63FPX relay circuit.

4) MES and Design Engineering personnel will evaluate the setpoint for acoustic monitoring of the PZR code safety valves for PZR PORV cycling events and determine if the setpoint should be changed.

5) Transmission Department personnel will continue evaluation of the failed 21LC relay contact. This may include sending the relay to A. Brown Boveri, Inc. for analysis. They will also investigate other modifications performed earlier to determine if this could have caused failure of the relay.

6) General Office OPS personnel will verify that an adequate emergency plan exists to restore power to the station in the event of a loss of both switchyards.

SAFETY ANALYSIS:

This event resulted in a Reactor Trip with the plant being capable of returning to operation. When the blackout logic was initiated, D/Gs 1A and 1B started, and all 10 load groups were sequenced on within 11 seconds (after the load sequencer initiated). The total load was well below the D/G capacity. If the D/Gs had not started and loaded properly, OPS personnel would have referred to emergency procedures which provide instruction to energize the 4.16 KV buses from Unit 2 if necessary. Offsite power was available to both essential 4.16 KV buses from Unit 2 through standby transformers SATA and SATB.

Upon loss of power to the NC pumps, coolant flow necessary for core cooling and the removal of residual heat was maintained by natural circulation in the NC system, aided by Auxiliary Feedwater in the secondary system. OPS personnel were aware of this and were monitoring subcooling parameters. Adequate subcooling margin was always maintained during the event.

Offsite power was restored within 40 minutes of the loss of power.

Approximately 17 minutes into the event an SI occurred due to low steam line pressure. Both NI pumps and 1 NV pump (1NV pump was already running) started. Low steam line pressure resulted when a steam header isolation valve remained partially open while steam pressure continued to be reduced by steam usage on the secondary side. OPS personnel were aware of decreasing steam pressure and were in the process of securing steam usage and isolating leaks when the SI occurred. It has been determined that there was no equipment or structural damage as a result of the SI.

Pressurizer PORVs 1NC-32 and 1NC-36 opened as required to maintain NC system pressure at approximately 2335 psig. The Pressurizer and Steam Generator code safety valves were not challenged during the event. Integrity of the Pressurizer Relief Tank Rupture Disk was not challenged.

An Unusual Event was declared and the TSC was activated as a precaution because of the loss of offsite power and SI.

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The lower containment air temperature spiked at 140 degrees Fahrenheit due to the VL air handling units tripping off during the loss of power. A visual inspection was performed and it has been determined that there was no equipment or structural damage as a result of the SI. These units are not powered by the D/Gs. The increased temperature resulted in an air volume expansion in lower containment. This caused the Ice Condenser Doors to open briefly as designed. Maximum pressure experienced was 0.76 psig which is well below the 3 psig setpoint for actuation of containment spray.

All Secondary system and accident mitigation equipment functioned as expected and no nuclear safety concerns occurred as a result of this incident. There were no challenges to fission product barriers as a result of this event.

There were no personnel injuries or radiological releases as a result of the event.

The health and safety of the public were unaffected by this event.

ADDITIONAL INFORMATION:

Sequence Of Events:

TR	-	Trip Report
PR	-	Personnel Recollection
ERI	-	Switchyard Events Recorder
LB	-	Logbooks (TSC, OSC, SRO, etc.)
WR	-	Work Request History
ER2	-	Plant Events Recorder

Date	Time	Event
8/21/90		Relay 21LC preventative maintenance was performed by Transmission Department personnel. (WR)
2/11/91	approx. 0730	The load dispatcher was contacted by the Relay crew. The load dispatcher stated a 35 minute outage of the autotransformer would be acceptable later in the day. (PR)
	approx. 1000	The new 63FPX relay circuit was installed for the autotransformer bank. (PR)
	approx.	The load dispatcher was contacted about testing the

1001	relay. System load had increased and it was not possible to perform the post modification (mod) test at that time with the autotransformer isolated. (PR)
1200	The modification crew brainstormed a test method that could be implemented while the autotransformer was energized. (PR)

approx. 1300	The Relay Supervisor noticed another crew working near the transformer. (PR)
1339	The onsite Operating Department Representative called the AOC to get permission for the Relay crew to proceed with the test. (PR)
approx. 1340	The post mod test was implemented but problems were encountered due to the blocking switch being labeled backwards. (PR)
approx. 1350	The blocking switch was re-labeled and the test resumed. (PR)
1355:01	The 86 relay detected a fault on the autotransformer bank and cleared both switchyard buses. (ERI)
1355:02	The Craighead White line was cleared due to failed 2ILC relay and overload. (ERI)
1355:04	The Mecklenburg Black line was cleared due to overload. (ERI)
1355:13	NI power range initiated a Reactor Trip due to high flux rate. (ER2)
1355:14	The Turbine tripped due to a reactor trip. (ER2)
----	D/Gs 1A and 1B started. (ER2)
1355:19	OPS personnel manually opened the Reactor Trip Breakers. (ER2)
1355:34	OPS personnel manually started NV pump B. (TR)
----	The Turbine Driven Auxiliary Feedwater pump (TD AFWP) started. (ER2)
1359	The condenser was in full load rejection mode. (ER2)
1400	Feedwater isolated due to Tavg less than 553 degrees Fahrenheit. (ER2)
1402	NC system letdown was isolated. (TR)
1412	An SM line isolation signal was initiated due to low pressure in loop A. SI was initiated. The ice condenser doors opened. (ER2)
1420	An Unusual Event was declared. (LB)

1422:33 The SI signal was reset. (ER2)

1435 Power was fully restored to the unit and available to the NC pump motors. (LB)

1452 Both VC/YC chillers were down. The OAC was down. (LB)

1503 The OSC and TSC were activated. (LB)

1505 A Train VC/YC was running. (LB)

1510 The TD AFWP was stopped. (LB)

1513 OPS personnel began swapping loads from the D/G supply buses to the normal 4160 volt supply buses. (LB)

1520 SM header was pressurized. (LB)

1529 The OAC was placed back in service.

1537 Containment pressure increased to approximately 0.5 psig. Lower containment temperature increased to 140 degrees Fahrenheit. (LB)

1539 Containment pressure increased to 0.7 psig. (LB)

1544 TSC personnel decided to cool the unit by venting steam through the SM atmospheric PORVs. (LB)

1600 PZR pressure was 2240 psi and NC loop B temperature was 554.7 degrees Fahrenheit. (LB)

1607 NC Pump B was started. (LB)

1612 Two lower containment ventilation units are in service. (LB)

1622 Containment pressure decreased to 0.3 psig. High pressure station air was available. (LB)

1629 Low pressure station air was available. (LB)

1637 Control Room OPS personnel moved into the normal shutdown procedure. (LB)

1643 The Unusual Event was de-escalated. (LB)

1649 Two Condenser Circulating Water System [EIIS:KG] pumps were available and OPS personnel were preparing to dump steam to the condenser. (LB)

1701 NC Pump A was running. Management personnel discussed sending an inspection team into containment. (LB)

1724 OPS personnel started Hotwell pump A. (LB)

1735 The OSC and TSC were de-activated. (LB)

2/13/91 0345 The Reactor was re-started. (LB)

TEXT PAGE 18 OF 18

Figure "McGuire Nuclear Station" omitted.

ATTACHMENT 1 TO 9103210199 PAGE 1 OF 1

Duke Power Company
McGuire Nuclear Station (704)875-4000
12700 Hagers Ferry Road
Huntersville, NC 28078-8985

DUKE POWER

March 13, 1991

U.S. Nuclear Regulatory Commission
Document Control Desk
Washington, D.C. 20555

Subject: McGuire Nuclear Station Unit 1
Docket No. 50-369
Licensee Event Report 369/91-01

Gentlemen:

Pursuant to 10 CFR 50.73 Sections (a)(1) and (d), attached is Licensee Event Report 369/91-01 concerning a Unit 1 Reactor Trip which occurred due to a loss of Offsite Power. This report is being submitted in accordance with 10 CFR 50.73(a)(2)(iv). This event is considered to be of no significance with respect to the health and safety of the public.

Very truly yours,

T.L. McConnell

DVE/ADJ/cbl

Attachment

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